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| NPRR Number | [1006](http://www.ercot.com/mktrules/issues/NPRR1006) | NPRR Title | Update Emergency Response Service (ERS) Restoration Assumption for Reliability Deployment Price Adder to Match Actual Data |
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| Date | April 9, 2020 |
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| Submitter’s Information |
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| Market Segment | Independent Generator and Independent Power Marketer (IPM) |

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| Comments |

 TCPA appreciates the intent of this Nodal Protocol Revision Request (NPRR) to better align the Reliability Deployment Price Adder (RDPA) for Emergency Response Service (ERS) deployment with time the resources are Off-Line.

 Summer 2019 provided some data in which more context can be derived for summer, however, it would be inappropriate to conclude that two days’ experience with ERS deployment is conclusive or definitive. While August 13 showed 100% return to service by three (3) hours, August 15 showed a longer time period for 100% return to service. In addition, ERS is a year-round program that may be and has been deployed during winter months as well as summer. The most recent winter deployment was January 2014 in which return to service was significantly longer at 7.5 hours. Any change should encompass return to service timeframes for both summer and winter months. It is important for both Load and generation to achieve the most accurate pricing possible to ensure market signals send the right message to both Market Segments.

 TCPA agrees that ten (10) hours is likely too long to maintain the RDPA but is concerned that three (3) hours is too short a time period and not reflective of return to service times for different seasons. The three data points available yield an average return to service timeframe of 4.67 hours and encompasses both summer and winter ERS deployments. As a result, TCPA is recommending a more reasonable and measured reduction to four-and-a-half (4.5) hours and a commitment to review the timeframe following the availability of additional data that may provide a more realistic view of return to service timeframes.

 Additionally, inclusion of Transmission and/or Distribution Service Provider (TDSP) Load management program deployments is consistent with the intent of the RDPA and accounts for out of market reliability actions to support accurate pricing signals. As such, TCPA has included TDSP standard offer Load management programs to ensure that ERCOT-instructed deployments during Energy Emergency Alert(s) (EEAs) be properly and consistently reflected in the RDPA. Inclusion of these programs is an appropriate accounting of measured and defined out-of-market actions that result in peak shaving and similar to ERS.

 TCPA appreciates the work to align reliability measures and market outcomes. With the recommended changes, TCPA believes all Market Segments will benefit from the balance struck by this NPRR.

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| Revised Cover Page Language |
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| NPRR Number | 1006 | NPRR Title | Update Reliability Deployment Price Adder Inputs to Match Actual Data |
| Requested Resolution  | Urgent. The current restoration presumption adopted through Nodal Protocol Revision Request (NPRR) 626, Reliability Deployment Price Adder (“formerly ORDC Price Reversal Mitigation Enhancements”), caused prolonged high Reliability Deployment Price Adder values for many hours after Energy Emergency Alert (EEA) conditions subsided during the summer of 2019. This value should be updated to reflect a more realistic number than ten but recognize that two days of data during summer does not represent a definitive number. Over-correction should be avoided in order to balance between variations in restoration time that exceed three hours but are less than ten hours. The proposed changes reflect the Emergency Response Service (ERS) deployment during both summer and winter months and reflects a more reasonable return to service timeframe. Market Participants can review this when additional data may be available. Additionally, the Reliability Deployment Price Adder calculation has been updated to incorporate ERCOT instructions to Transmission and/or Distribution Service Providers (TDSPs) to deploy Load management programs during an EEA. .  |
| Revision Description | When the Reliability Deployment Price Adder was created through NPRR626, ERS Resources were presumed to return to service on a linear curve over ten hours following recall. However, NPRR626 explicitly stated that: “The restoration period shall be reviewed by TAC at least annually, and ERCOT may recommend a new restoration period to reflect observed historical restoration patterns.” [Actual data from summer 2019](https://urldefense.proofpoint.com/v2/url?u=http-3A__www.ercot.com_content_wcm_key-5Fdocuments-5Flists_186843_2.-5FTAC-5F-2D-5FReview-5Fof-5FERS-5FRestoration-5FPeriod.pptx&d=DwMFAg&c=hz4DKlNTyZ4d1MxSH4qd17OJdrdn2xGa7PDwVHihKdw&r=Uae3Yc03FrRk7Nrfze9TwepgpnJxwuVs7SFyGhw5Bhw&m=juI8hu1g_roMLO2xV45oaMKLTQKUJNz6jTXK6ozL_P8&s=6heQU8Bqd3bZdxymlq-QV_GANHb9NIBMJuR962w0l0k&e=) provided by ERCOT shows the following: * On August 13th, 38% returned to service after one hour, 78% returned to service after two hours, and 100% returned to service after three hours.
* On August 15th, 42% of the ERS MWs returned to service after one hour, 83% returned to service after two hours, and 93% returned to service after three hours.
* On January 6, 2014, ERS MWs returned to service after approximately 30 intervals or 7.5 hours.

It is appropriate to update the Reliability Deployment Price Adder inputs to reflect a more realistic time period based on the actual data from the ERS deployments last summer as well as those in winter months since ERS is a year-round program. Accordingly, this NPRR proposes to return the ERS resources in a linear curve over a four and a half-hour period following recall, rather than ten hours, to account for the data seen from summer 2019 as well as winter 2014 with the recognition that three days’ data does not provide definitive information for further reduction. The NPRR also changes the process for updating this parameter in the future so that it can be updated by TAC each year as appropriate, without the need to file an NPRR.During periods of EEA 2, ERCOT instructs TDSPs to reduce Load through deployment of any available Load management plans.The December 2019 Capacity Demand and Reserves Report notes TDSP Load management programs account for 257 MW of demand reduction capacity. Inclusion of this capacity in the Reliability Deployment Price Adder is consistent with its intent, which mitigates price distortions resulting from out-of-market actions.  |
| Business Case |  Adjusting the Reliability Deployment Price Adder ERS restoration assumption and including ERCOT-instructed Load reductions through the use of TDSP Load management programs provides more accurate pricing signals for Loads and generators. These enhancements avoid inefficient market response, preserve resources for other periods when response is actually needed, and limit unnecessary high prices for consumers after scarcity conditions have subsided. Implementation costs are easily justified by the pricing efficiencies this will provide.  |

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| Market Rules Notes |

Please note that the following NPRR(s) also propose revisions to the following section(s):

* NPRR1010, RTC – NP 6: Adjustment Period and Real-Time Operations
	+ Section 6.5.7.3.1
* NPRR1014, BESTF-4 Energy Storage Resource Single Model
	+ Section 6.5.7.3.1

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| Revised Proposed Protocol Language |

6.5.7.3.1 Determination of Real-Time On-Line Reliability Deployment Price Adder

(1) The following categories of reliability deployments are considered in the determination of the Real-Time On-Line Reliability Deployment Price Adder:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (12) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than Controllable Load Resources;

(d) Deployed Emergency Response Service (ERS);

(e) Real-Time DC Tie imports during an EEA where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) Real-Time DC Tie exports to address emergency conditions in the receiving electric grid;

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| [NPRR904: Replace items (e) and (f) above with the following upon system implementation and renumber accordingly:](e) ERCOT-directed DC Tie imports during an EEA or transmission emergency where the total adjustment shall not exceed 1,250 MW in a single interval; (f) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;(g) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT where the total adjustment shall not exceed 1,250 MW in a single interval;(h) ERCOT-directed DC Tie exports to address emergency conditions in the receiving electric grid where the total adjustment shall not exceed 1,250 MW in a single interval; (i) ERCOT-directed curtailment of DC Tie exports below the DC Tie advisory export limit as of 0600 in the Day-Ahead or subsequent advisory export limit during EEA, a transmission emergency, or to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;  |

(g) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;

(h) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid; and

(i) ERCOT-directed deployment of TDSP standard offer Load management programs.

(2) The Real-Time On-Line Reliability Deployment Price Adder is an estimation of the impact to energy prices due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, after the two-step SCED process and also after the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder have been determined, the Real-Time On-Line Reliability Deployment Price Adder is determined as follows:

(a) For RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line, set the LSL, LASL, and LDL to zero.

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| [NPRR884: Insert paragraph (b) below upon system implementation and renumber accordingly:](b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity, set the LSL, LASL, and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction. |

(b) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes \* SCED Down Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes\*SCED Up Ramp Rate), or HASL.

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| [NPRR904: Replace paragraph (b) above with the following upon system implementation:](b) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:(i) If the Generation Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes \* SCED Down Ramp Rate), or LASL; and(ii) If the Generation Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes \* SCED Up Ramp Rate), or HASL. |

(c) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes \* SCED Up Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes\*SCED Down Ramp Rate), or HASL.

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| [NPRR904: Replace paragraph (c) above with the following upon system implementation:](c) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:(i) If the Controllable Load Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes \* SCED Up Ramp Rate), or LASL; and(ii) If the Controllable Load Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes \* SCED Down Ramp Rate), or HASL. |

(d) Add the deployed MW from Load Resources other than Controllable Load Resources to GTBD linearly ramped over the 10-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the amount of MW added to GTBD during the restoration period will be determined by validated telemetry. The TAC shall review the validity of the prices for the bid curve at least annually.

(e) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period (“RHours”)..

The above parameter is defined as follows:

| Parameter | Unit | Current Value\* |
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| RHours | Hours | Four and a half (4.5) |
| \* The current value of the parameter(s) referenced in this table above will be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value. If TAC is unable to recommend a new value(s) for the parameter(s) referenced in this table above the values shall stay the same. |

(f) Add the MW from Real-Time DC Tie imports during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(g) Subtract the MW from Real-Time DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

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| [NPRR904: Replace paragraphs (f) and (g) above with the following upon system implementation and renumber accordingly:](f) Add the MW from DC Tie imports during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.(g) Add the MW from DC Tie export curtailments during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator. The MW added to GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for exports on that tie as of 0600 in the Day-Ahead or subsequent advisory export limit minus the aggregate export on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.(h) Subtract the MW from DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator. (i) Subtract the MW from DC Tie import curtailments to address local transmission system limitations or emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator. The MW subtracted from GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for imports on that tie as of 0600 in the Day-Ahead or subsequent advisory import limit minus the aggregate import on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator. |

(h) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(i) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(j) Add the MWs from TDSP standard offer Load management programs to GTBD. When ERCOT instructs TDSPs to implement Load management programs the total amount of deployed MW shall be the sum of TDSP Load management capacity values authorized by the Public Utility Commission of Texas (PUCT), including but not limited to the value ERCOT provided in the Capacity Demand and Reserve Report. After recall, an approximation of the amount of un-restored TDSP standard offer Load management programs shall be used. GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period (“RHours”) defined by item (e) above.

(k) Perform a SCED with changes to the inputs in items (a) through (i) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.

(l) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.

(m) Perform a SCED with the changes to the inputs in items (a) through (j) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy offer Curves.

(n) Determine the positive difference between the System Lambda from item (m) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(o) Determine the amount given by the Value of Lost Load (VOLL) minus the sum of the System Lambda of the second step in the two step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder.

(p) The Real-Time On-Line Reliability Deployment Price Adder is the minimum of items (n) and (o) above.